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Assessment of integrated gasification combined cycle technology competitiveness

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Abstract

In this work, a parametric cost-benefit analysis concerning the use of integrated gasification combined cycle (IGCC) technology (with and without carbon capture and storage) is carried out. For the analysis, the IPP optimization software is used in which the electricity unit cost from various power generation technologies is calculated. For comparison purposes, the Rankine cycle (with heavy fuel oil or coal as fuel) and the combined cycle (with natural gas or gasoil as fuel) technologies are also examined. The parametric study carried out, using a range of load factors from 50% to 90% and a range of efficiencies for IGCC technology between 40% and 55%, yields encouraging results for the viability of this emerging technology.

Keywords: Power generation; IGCC cycle; Zero emission power plants; Carbon capture and storage

Contents

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1. Introduction

The energy industry today is facing serious challenges. The world energy demand is increasing at an alarming rate (an increase of 60% is expected in the next 30 years), there is a pressing need for drastic decrease of the greenhouse gases emissions in order to mitigate the effects of climate change and the volatility of the oil prices and the geopolitical instability in the oil producing regions is damaging the reliability and security of energy supply. To answer these challenges, it is necessary to formulate and develop adequate solutions as soon as possible.

The European Union's (EU) main long-term goal in the field of energy is the conversion of the existing EU energy system, which is heavily dependent on fossil fuels, to a sustainable energy system based on differentiated energy sources of higher energy efficiency. This will enable the EU to face the challenges posed by the security of the energy supply and the climate change while, at the same time, increasing the competitiveness of the European energy industries.

Currently, oil holds an important position in the EU energy system since it is used widely in the industrial, residential and transport sectors. Natural gas is also used in all sectors including electricity generation (together with coal and nuclear energy). In the envisaged energy system of 2020, based on the long-term energy targets of the EU, the use of oil will be limited only to the transport sector. Natural gas will emerge as the dominant energy source. In addition, the novel technologies of natural gas reforming and coal gasification with carbon capture and sequestration will, also, be used for hydrogen production which is an environmentally friendly fuel, free of harmful emissions. This will lead, further, to the creation of the first hydrogen communities in which green hydrogen will be produced from renewable energy sources of distributed generation. The first hydrogen power generation units, called hydrogen power generation (HYPOGEN) plants [1,2], will be in commercial use and will cover part of the electricity demand without any harmful emissions of carbon dioxide. By 2040, it is hoped that oil will be fully substituted by hydrogen as an energy source. Hydrogen will be generated either by the reforming of natural gas and gasification of coal or by renewable energy sources. This step will complete the transformation of the existing energy economy to a hydrogen economy.

It is internationally acclaimed today that the technology of integrated gasification combined cycle (IGCC) is one of the most important bulwarks of the future hydrogen economy, which HYPOGEN plants will be based on. The scientific community and the major corporations of electricity generation consider the technology used in IGCC as one of the most promising technologies for the production of cleaner electrical power in the future. This is underlined by the increasing amount of funding available for research projects [3] that are closely related to electricity generation with the use of hydrogen (or synthesis gas) and by the development of joint ventures between major corporations in the energy sector to fund the construction and operation of IGCC-based hydrogen power plants across Europe [4].

It should be noted that although each major component of IGCC has been broadly utilized in industrial and power generation applications, the integration of a gasification island with a combined cycle power plant is relatively new. This integration for commercial electricity generation has been demonstrated by a number of facilities around the world, but is not yet perceived to be a mature, commercial technology with clearly understood costs and risks.

The objective of this work is to carry out a technical and economic analysis concerning the use of an IGCC technology, with and without carbon capture and storage (CCS), for power generation and compare it to the existing conventional power generation technologies. A parametric study is carried out with variations in efficiency of the IGCC plant and compared on a cost-benefit basis with Rankine cycle power plants (using both coal or heavy fuel oil (HFO)) and with combined cycle plants (using both natural gas or gasoil). The analysis is performed using the IPP optimization software that takes into consideration the capital cost, the fuel cost and operation and maintenance requirements of each candidate scheme and calculates the least cost configuration and the ranking order of the candidate power technologies [5].

In Section 2, the IGCC technology is presented including a description of the major stages and components of the cycle. In Section 3, the IPP software is illustrated and in Section 4, the cost–benefit analysis is presented and the results for the various technologies under investigation are discussed. The conclusions are summarized in Section 5.

2. IGCC technology description

IGCC technology is a power generation process that integrates a gasification system with a combined cycle power plant [6]. The gasification system converts coal (or other carbon-based feedstocks such as petroleum coke, heavy oils, biomass, etc.) into synthesis gas (syngas) which consists primarily of hydrogen (H_2) and carbon monoxide (CO). The syngas (H_2/CO) is then used as fuel in a combined cycle power plant for electricity generation.

A typical configuration of an IGCC power plant without CCS is illustrated in Fig. 1 and of the one with CCS is presented in Fig. 2. It comprises mainly four operating components, air separation unit, gasifier, syngas cooling and cleanup system, and combined cycle power plant [7].

The pressurized cryogenic air separation unit is responsible for the separation of air into its constituents and the supply of pure oxygen to the gasifier. The pressurized air required by the air separation unit can be supplied either entirely by the gas turbine compressor or entirely by a separate compressor or partially from the two compressors. The degree of integration between the air separation unit and the gas turbine is defined as the portion of the air required by the air separation unit that is extracted and supplied by the compressor of the gas turbine. In the case of full (100%) or partial integration, the nitrogen produced from the air separation unit is used as the syngas diluent prior to combustion. Thus, nitrogen is injected into the gas turbine's combustor burner and mixed with the syngas in order to control NO_X emissions, reduce the tendency for flashback during combustion and enhance the power output from the turbine [8]. In the case of zero degree of integration, the preferred diluent is either steam or water since the nitrogen originating from the air separation unit would be at low pressure and would require additional compression prior to mixing it with syngas [6]. The degree of integration can play a significant role in the overall performance and efficiency of the power plant. The relation between the degree of integration and the overall plant efficiency and output net power is illustrated in Fig. 3. Clearly, as the degree of integration increases and therefore the air separation unit is supplied with air from the gas turbine compressor, the net plant output power increases since the auxiliary power requirements of the air separation unit become less [9]. The gas turbine can still maintain its rated power output with the reduced amounts

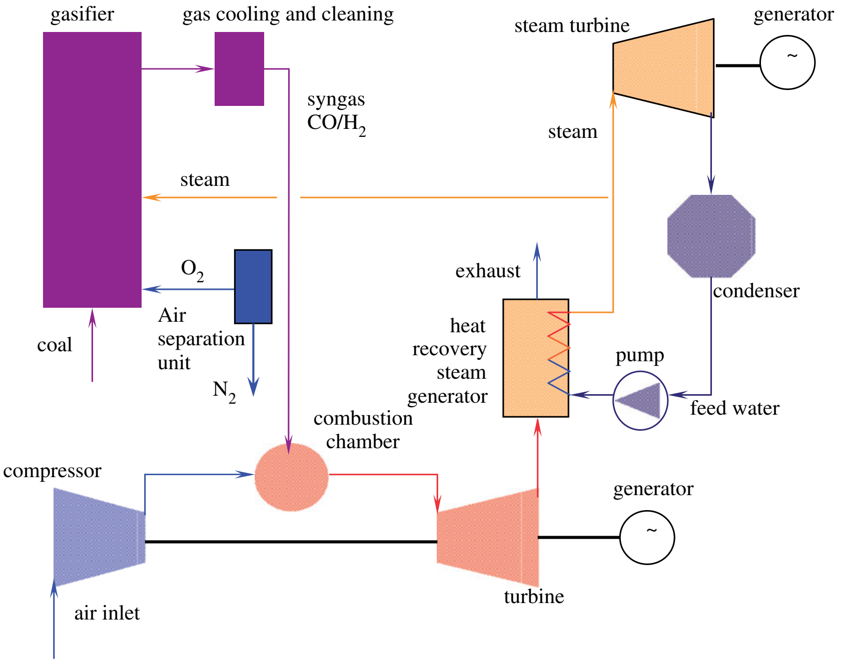

Fig. 1. General arrangement of IGCC technology without CCS.

of supplied gases. This is because syngas, due to its necessary dilution and chemical properties, has a much higher volumetric and mass flow rate in the combustor than natural gas. Therefore, contemporary gas turbines that are built for use with natural gas would require fewer amounts of combusted syngas to keep their rated power output. At some stage however, and as the degree of integration increases, the amount of air diverted towards the air separation unit starts to be sufficiently high to negatively affect gas turbine output performance. Thus, the net plant output power starts to be reduced.

Clearly, the degree of integration where the maximum net power is reached is not the same as the one where the maximum plant efficiency is reached. Maximum plant efficiency is reached at 100% integration, where the auxiliary power requirements of the air separation unit are minimal since all air is supplied from the gas turbine compressor. The degree of integration where the maximum plant output power is reached varies according to the type of the gas turbine used and the type of coal and gasifier used.

Oxygen-blown gasifiers, at high temperature and elevated pressure in the presence of oxygen and steam, convert carbon-based feedstocks into syngas (H_2/CO). Gasification is a partial oxidation process that occurs in reducing conditions (controlled shortage of oxygen) inside an enclosed pressurized reactor. Partial oxidation of the feedstock creates heat and a series of chemical reactions produce syngas. The alternative to oxygen-blown gasification is the air-blown gasification which eliminates the need for an air separation unit. However, air-blown gasification has the disadvantage of producing a syngas with lower calorific value [10], which is sometimes not desirable.

The gasifiers can be divided into three groups, namely, (a) the moving-bed reactors (also called fixed-bed), (b) the fluidized-bed reactors and (c) the entrained flow reactors.

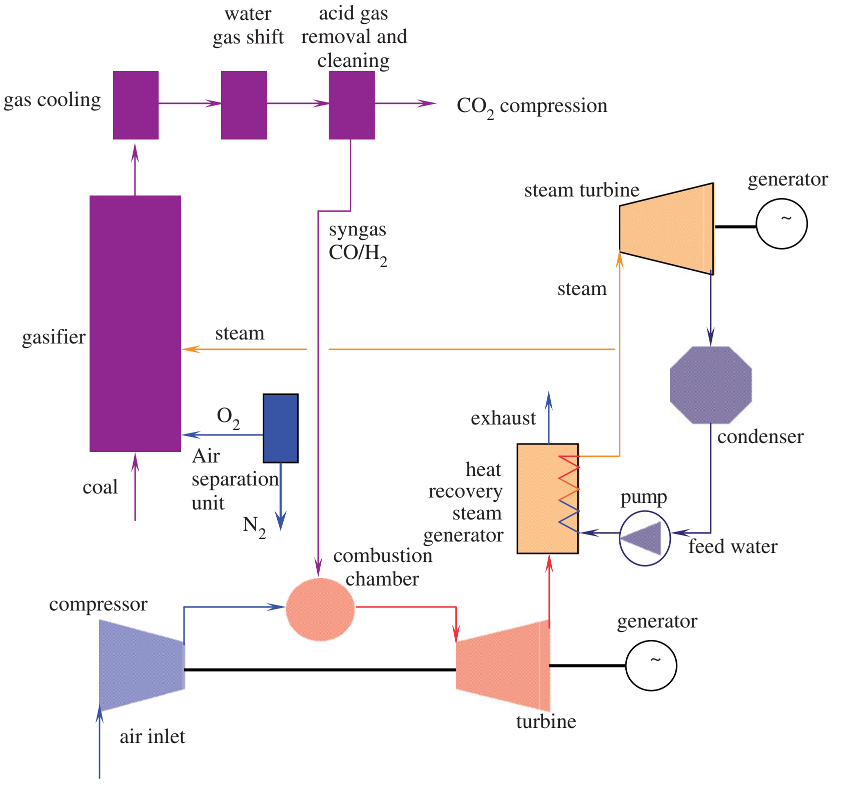

Fig. 2. General arrangement of IGCC technology with CCS.

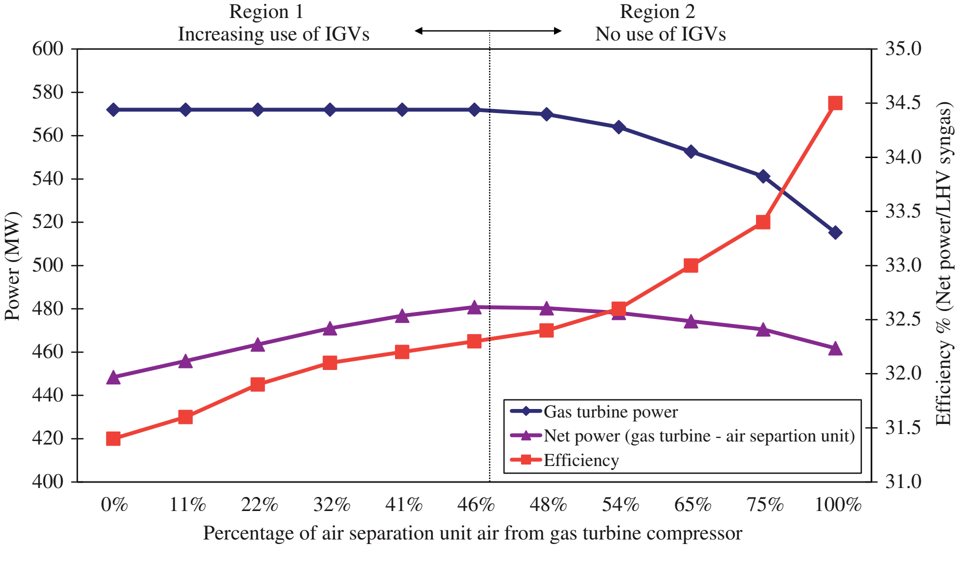

Fig. 3. Relation between degree of integration and plant efficiency (IGV = inlet guide vane).

In moving-bed reactors, large particles of the fuel move slowly down through the gasifier while reacting with the gasifying medium moving up through it. Several different reaction zones are created and they accomplish the gasification process. Operating temperatures are not uniform inside the reactor with the temperature of the syngas leaving the reactor being as low as 400–500 °C. In fluidized-bed reactors small particles of the fuel remain suspended in the gasifying medium while the gasification process takes place. The temperature inside the reactor remains uniform in the range of 800–1000 °C. In entrained flow reactors the pulverized fuel goes through the various stages of gasification flowing co-currently with the gasifying medium. The feedstock can be either in dry or in water slurry form. The temperatures achieved in the reactor are very high in the range of 1200–1600 °C. Entrained flow gasifiers are considered to be the most suited type for IGCC applications [9].

The raw syngas produced from the gasifiers contain (apart from CO and H_2) small quantities of carbon dioxide (CO_2), water (H_2O), nitrogen (N_2), sulfur compounds (H_2S, COS), nitrogen compounds (NH_3, HCN), chlorine compounds (HCl, NH_4Cl), particulate matter (unconverted carbon and ash), methane (CH_4), mercury (Hg), etc. Prior to injecting the syngas in the combustor of the gas turbine the raw syngas has to be treated in order to be cleaned up. Due to the fact that the syngas leaves the gasifier at high temperatures, it has to be cooled down first.

Cooling of syngas is accomplished using a waste heat boiler or a direct quench process that injects water into the raw syngas. For particulate removal, ceramic or metallic filters are used located upstream of the heat recovery device, or water scrubbers which are located downstream of the cooling devices are used. Next, the syngas is treated in "cold-gas" clean-up process (called acid gas removal process) to remove the sulfur and nitrogen compounds. This process can be either chemical or physical solvent-based process. Other compounds such as HCl and NH_3 are removed using water scrubbing. Traces of mercury are also removed from syngas using a sulfur-impregnated activated carbon bed.

After cleanup, the syngas is directed to the combined cycle power plant [11]. The syngas is used as fuel in the combustor of the gas turbine. The hot exhaust gases produced after combustion of syngas are captured and directed to a heat recovery steam generator to generate steam which, in turn, is fed to a steam turbine to complete the combined power cycle. The exhaust gases leave the heat recovery steam generator through a stack in the atmosphere. Due to the cleanup of the syngas prior to combustion these exhaust gases are environment friendly containing much smaller amounts of SO_2, NO_X, CO_2 and particulate matter compared with other coal-based technologies [9].

It is acknowledged that greenhouse gas emissions from an IGCC plant are much lower than those from a typical pulverized coal plant. However, the need for further reduction of harmful emissions to the environment (Kyoto protocol) and the developments in technology have advanced the idea of an IGCC plant incorporating CCS. Such a plant would provide minimal harmful emissions while still having the advantages of a standard IGCC plant (cheaper and abundant fuel, marketable by-products) plus the possibility of pure hydrogen co-production for storage or fuel cell applications. Essentially such a plant would embody the HYPOGEN principle as envisaged by the EU [2].

Recent studies have shown that an IGCC plant with CCS requires two additional pre-combustion stages than the conventional IGCC cycle plant as illustrated in Fig. 2. The two additional stages are the water gas shift reaction and the acid gas removal for the removal of CO_2 from the syngas. In addition, a CO_2 compression stage is necessary to make transportation and storage of the sequestered quantity of CO_2 feasible. The downside is

that these additional stages reduce overall plant efficiency when compared to the IGCC plant without CCS. Plant efficiency partly decreases because internal power is required to drive the CO_2 compression stage [12,13]. Another reason for efficiency decrease is that after the superimposition of the two additional stages (before syngas combustion), the amount of coal feed required to provide the necessary rate of chemical fuel energy to the gas turbine needs to be increased. In turn, this can result in lower steam/carbon ratio in the gasifier which would necessitate the supply of additional steam from the stream cycle and thus lower plant output power even further [9]. The amount of efficiency penalty for the IGCC plant with CCS also depends heavily on the type of gasifier used.

An important factor to be considered before the technical and economic parameters of such a plant are determined for the cost–benefit analysis is the capture efficiency of the plant. Clearly, the degree of capture efficiency will influence the final cost of electricity and therefore needs to be decided in advance. Although no commercial IGCC plant with CCS has been built yet, the typical value of capture efficiency considered in recent studies is 90% [14]. One factor that may limit the level of capture efficiency of the plant is that contemporary gas turbines are not guaranteed to function with fuel syngas having more than 65% hydrogen content. Clearly with higher capture efficiencies, the hydrogen content of syngas increases to levels that cannot be tolerated for electricity production with the current gas turbine designs.

The water gas shift process is described briefly below. During the water gas shift process, the exothermic water gas shift reaction transfers the fuel heating value from CO to H_2 and transfers the carbon from CO to CO_2. This changes the chemical composition of the syngas towards more H_2 and less CO. There are two important reasons that justify the use of this additional stage in the process of CO_2 capture. The first reason is that the conversion of water and CO into H_2 increases the total amount of hydrogen production for a given quantity of input fossil fuel. The second reason is that the available quantity of CO is minimized since it is effectively being converted into CO_2. By this the capture efficiency of CO_2 is increased. Therefore, this enhances the process of CO_2 sequestration and pure hydrogen production. For maximum conversion of CO and, therefore, maximum hydrogen production, low temperatures are applied in the shift reactors. The raw syngas is therefore, cooled after it exits the gasifier so that it reaches typical temperatures between 200 and 500 °C. It then reacts with water vapor or steam in the shift reactor in the presence of H_2S. For maximum CO conversion, the shift reaction is repeated in a second stage/reactor which is at a lower temperature than the first. The syngas exiting the water gas shift reaction has a much higher composition of hydrogen than the raw syngas but still requires to be treated for CO_2 and sulfur (H_2S) sequestration. The water gas shift stage can be employed in the sour shift conversion or in the clean shift conversion mode. In the sour shift, which is the preferred mode of operation, the shift reaction stage takes place before the syngas acid gas removal stage (Fig. 2).

3. Simulation software

The technical and economic analysis is carried out using the IPP optimization algorithm [5,15]. This user-friendly software tool takes into account capital cost, fuel cost and operation and maintenance (O&M) requirements of each candidate scheme, and calculates the least cost configuration and the ranking order of the candidate power technologies. The economic parameters of each candidate technology are evaluated

in terms of a cost function:

$$\min\left(\frac{\partial c}{\partial k}\right) = \min\left\{\frac{\sum_{j=0}^{N}[((\partial C_{Cj}/\partial k) + (\partial C_{Fj}/\partial k) + (\partial C_{OMFj}/\partial k) + (\partial C_{OMVj}/\partial k))/(1+i)^{j}]}{\sum_{j=0}^{N}[(\partial P_j/\partial k)/(1+i)^{j}]}\right\}, \tag{1}$$

where c is the generated electricity unit cost in US$/kWh, in current prices, for the candidate technology k, C_{Cj} is the capital cost function in US$ which can be amortized, for example, during the construction period of each candidate plant, C_{Fj} is the fuel cost function in US$, C_{OMFj} is the fixed O&M cost function in US$, C_{OMVj} is the variable O&M cost function in US$, P_j is the energy production in kWh, $j = 1, 2, \ldots, N$ indicates the year under consideration, and i is the discount rate. The optimum solution can then be obtained by

$$\text{least cost solution} = \min[c_k]. \tag{2}$$

All costs are discounted to a reference date at a given discount rate. Each run can handle 30 different candidate schemes simultaneously. Based on the above input parameters for each candidate technology the algorithm calculates the least cost power generation configuration in current prices and the ranking order of the candidate schemes. Details of the optimization algorithm implementing the above mathematical formulation can be found in Ref. [5].

4. Cost–benefit analysis

The IGCC technology is new and still under development with only a handful of pilot plants existing worldwide, as tabulated in Table 1. The widely used power generation technologies considered for comparison with the IGCC cycle is the combined cycle and the Rankine cycle. These technologies are mature and are used extensively for power generation for decades in every corner of the world. Combined cycle technology will be

Table 1
IGCC pilot plants around the world

Plant name	Country	Installation date	Capacity (MWe)	Fuel
Cool Water	USA	1984	100	Coal
NUON	Netherlands	1994	253	Coal
Wabash River	USA	1995	262	Coal
Polk Power	USA	1996	250	Coal
SUV	Slovakia	1997	350	Coal
Elcogas	Spain	1998	335	Coal/petroleum coke
ISAB	Italy	2000	510	Oil residuals
Sarlux	Italy	2000	545	Oil residuals
API Energia	Italy	2001	280	Oil residuals
Exxon	Singapore	2001	180	Oil residuals
Motiva	USA	2002	160	Petroleum coke
Negishi	Japan	2003	342	Oil residuals

examined using both gasoil or natural gas as fuel, while the Rankine cycle will be examined using coal or HFO.

In the case of the IGCC technology, the cost–benefit analysis will be conducted with and without CCS. Furthermore, IGCC cycle in both cases will be examined for a range of efficiencies from 40% to 55%. The reason for using multiple efficiencies for the IGCC technology is the continuous and ongoing improvements to the individual components that make up the IGCC cycle. These improvements are effecting higher efficiencies for the IGCC plant and net efficiencies of up to 55% are envisaged in the future from around 40% today [16]. The effect of the increase on IGCC plant efficiency is of paramount importance to the results of the cost–benefit analysis. Examples of improvements to the components of the IGCC cycle which can result in higher efficiency are the increase of the syngas clean-up temperature (moving from cold to hot mode of operation) and the modifications to the existing gas turbines burner nozzles and combustor chambers for specific use with syngas instead of natural gas, which allows for output power augmentation and more effective syngas combustion.

For the purpose of the analysis the IGCC gasifier was taken to be an oxygen-blown entrained flow gasifier with dry coal feed. No spare gasifier was assumed to be required at the plant. The IGCC cycle employed a zero degree of integration between the air separation unit and the gas turbine and no dilution of syngas with nitrogen was effective.

The technical and economic parameters of all candidate technologies are presented in Table 2. The capital costs, including infrastructure costs of the IGCC plant and for the rest of the candidate technologies, were based on 2006 ''overnight'' costs of a greenfield plant and have been amortized during the whole 25 years of the plant's useful operating life. The fuel costs for all candidate technologies (coal, HFO, natural gas and gasoil) were based on the scenario shown in Fig. 4. A discount rate of 6% and inflation rate of 2% were used in the calculations. Sixty runs in total were conducted using the IPP software, and the results obtained are illustrated in Figs. 5–7.

Table 2
Technical and economical parameters of the candidate technologies

Option no.	Technology	CCS	Fuel type	Capacity (MWe)	Capital cost (US$/kW)	Efficiency (%)	Load factor (%)	Fuel net calorific value (GJ/t)	Fixed O&M (US$/kW month)	Variable O&M (US$/MWh)
1	Rankine cycle	No	Coal	250	1380	36.2	50–90	26.8	4.51	2.26
2	Rankine cycle	No	HFO	250	1320	37.3	50–90	41.3	2.97	0.49
3	Combined cycle	No	Gasoil	250	1000	50.8	50–90	42.5	2.71	4.64
4	Combined cycle	No	Natural gas	250	1000	53.5	50–90	45.0	2.48	2.50
5	IGCC	No	Coal	250	1450	40.0	50–90	26.8	3.60	1.75
6	IGCC	No	Coal	250	1450	45.0	50–90	26.8	3.60	1.75
7	IGCC	No	Coal	250	1450	50.0	50–90	26.8	3.60	1.75
8	IGCC	No	Coal	250	1450	55.0	50–90	26.8	3.60	1.75
9	IGCC/CCS	Yes	Coal	250	2000	40.0	50–90	26.8	4.00	1.78
10	IGCC/CCS	Yes	Coal	250	2000	45.0	50–90	26.8	4.00	1.78
11	IGCC/CCS	Yes	Coal	250	2000	50.0	50–90	26.8	4.00	1.78
12	IGCC/CCS	Yes	Coal	250	2000	55.0	50–90	26.8	4.00	1.78

Fig. 5 shows the electricity unit cost of each candidate technology for different values of load factor. For all technologies and schemes, as the load factor increases the electricity unit cost decreases. As it can be seen from the graph, the least cost technology is the Rankine cycle which uses coal as fuel. However, the Rankine cycle technology with HFO as fuel is the second most expensive technology. This is due to the to the foreseen difference

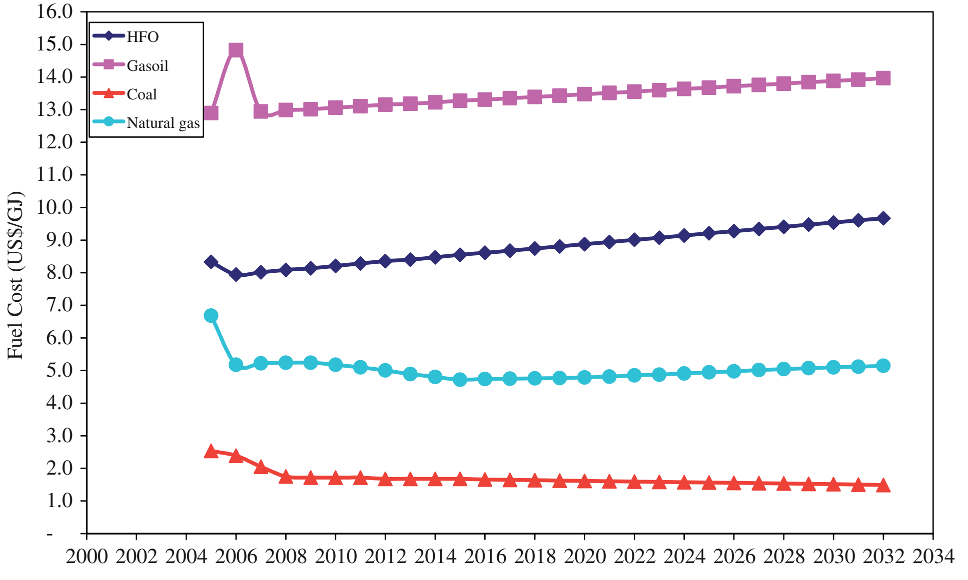

Fig. 4. Fuel cost projections.

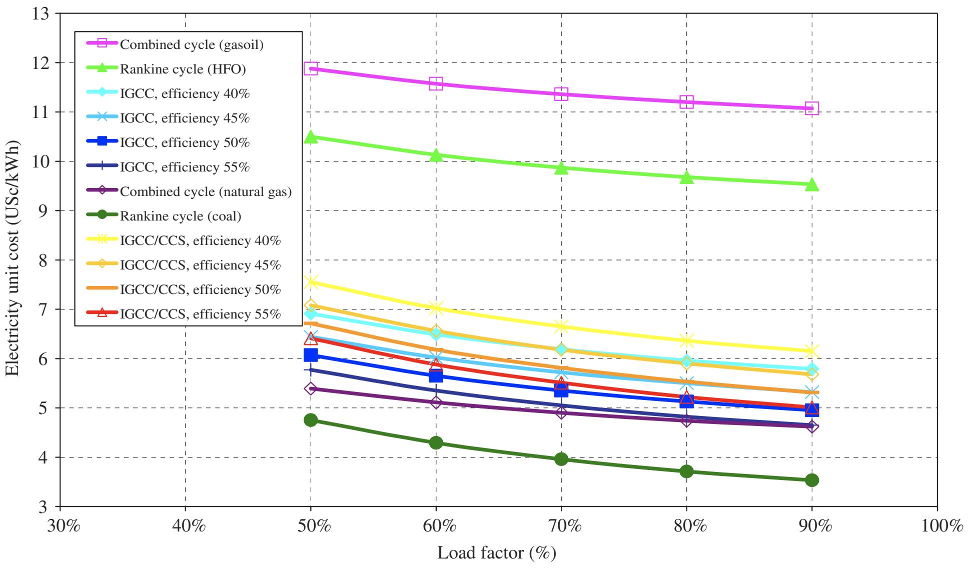

Fig. 5. Electricity unit cost for various capacity factors.

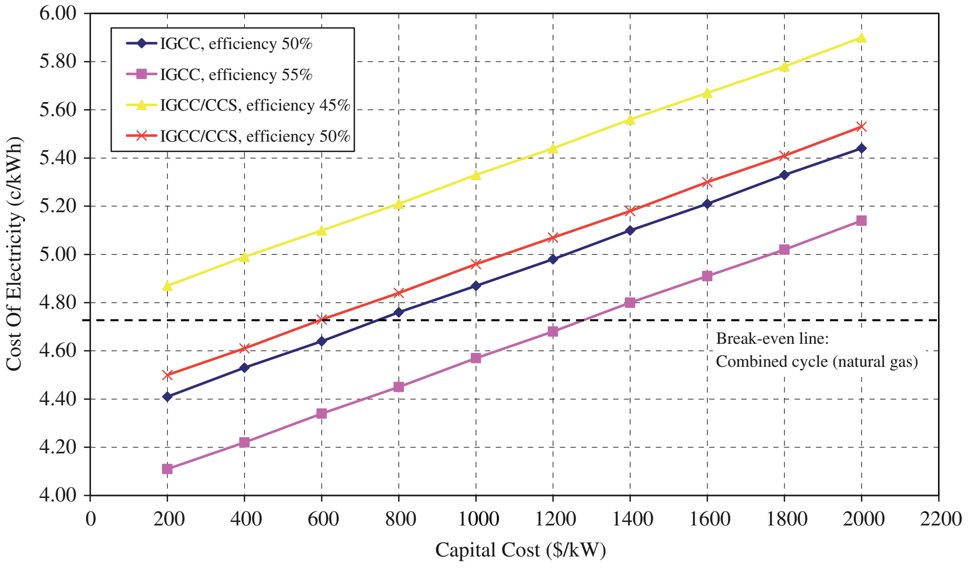

Fig. 6. Electricity unit cost for various IGCC technology capital cost at 80% load factor.

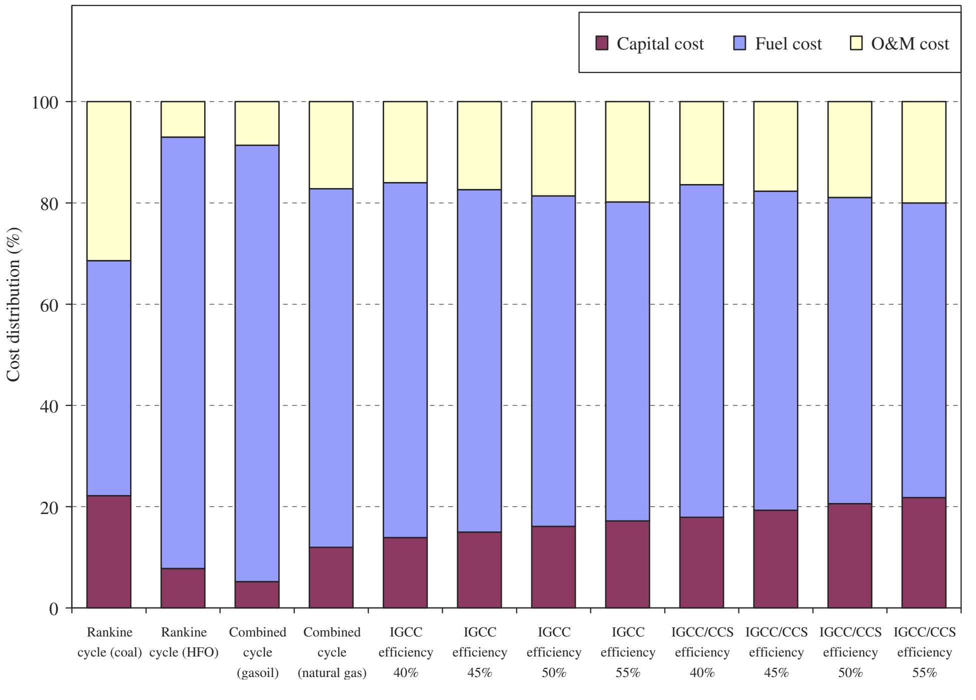

Fig. 7. Percentage cost distribution of each candidate technology at 80% capacity factor.

of fuel price between coal and HFO. This is also true for the case of combined cycle technology with gasoil and natural gas fuels. Natural gas price compared to gasoil price is much lower and this is reflected on the overall electricity unit cost. While natural gas

combined cycle is the second cheapest technology, combined cycle with gasoil fuel is the most expensive one. For IGCC technology, the higher the efficiency of the plant is, the less is the electricity unit cost. This logical result stresses the importance of achieving as high efficiency as possible. IGCC technology with CCS is, as expected, more expensive than that without CCS. The difference in electricity unit cost between IGCC with and without CCS decreases as the load factor of the unit increases. The electricity unit cost for this technology (both with and without CCS) lies between the four schemes examined above, towards the more economical ones.

Fig. 6 shows the electricity unit cost of an IGCC plant with and without CCS for a load factor of 80% for different values of capital cost and plant efficiencies. The critical ''break-even line'' in this graph is given by the electricity unit cost of a natural gas combined cycle plant with a capital cost of \$1000/kWh which is considered as a base-case scenario. Clearly, the high capital costs of an IGCC plant today result in electricity unit costs beyond the ''break-even line''. In the future, prospective IGCC plants with efficiencies 50% and 55% can produce electricity at competitive prices to the base-case scenario when capital costs are below approximately \$770/kWh for the 50% efficiency case and \$1300/kWh for the 55% efficiency case. The IGCC experiences and the research studies reported so far suggest that this is a viable expectation. On the other hand, IGCC plants with CCS cannot produce electricity at prices competitive to the base-case scenario unless in the future efficiencies reach values of 50%. In such a case, the plant capital costs need to be less than \$600/kWh for the electricity produced to be cheaper than the base-case scenario.

Fig. 7 shows a percentage breakdown of the total costs of each technology in terms of their capital, fuel and O&M costs. As a general comment, fuel cost occupies the higher portion of the total cost for all technologies. In the two most expensive technologies (combined cycle with gasoil and Rankine cycle with HFO) the percentage of the fuel cost to the total cost of the technologies can be as high as 85%. For the cheapest technology (Rankine cycle with coal), this figure is limited only to 45%. Rankine cycle with coal has the biggest portion of capital and O&M costs while on the contrary combined cycle with gasoil and the Rankine cycle with HFO have the lowest contribution. IGCC cost distribution resembles that of the combined cycle with natural gas. As the efficiency of the IGCC increases the percentage of the fuel to the total costs decreases, since with higher efficiencies less fuel is consumed in order to produce the same amount of energy. IGCC with CCS has higher percentage of capital cost and similar percentage of O&M cost compared to IGCC without CCS.

5. Conclusions

In this study a parametric cost–benefit analysis of IGCC technology was carried out in order to compare this newly emerging technology with other technologies used extensively for power generation. In particular, IGCC technology (with and without CCS) was compared with the combined cycle technology (gasoil or natural gas as fuel) and the Rankine cycle technology (coal or HFO as fuel).

The cost–benefit analysis yielded encouraging results concerning the viability of the IGCC technology. Although it is not a fully mature technology and it is constantly upgraded, the analysis indicates that it is a much more economical technology than combined cycle with gasoil and the Rankine cycle with HFO. Furthermore, IGCC technology, although more expensive at present, can be a competitive alternative to natural

gas combined cycle and to the Rankine cycle with coal as feedstock, bearing in mind that the capital costs of this new technology will drop significantly in the future (after massive production) and that the Rankine cycle technology with coal has high levels of primary and greenhouse emissions burdening it with huge environmental and economic penalties. IGCC with CCS is more expensive than IGCC without CCS due to the additional stages required but it has the undisputable benefit of cleaner emissions to the environment.

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